Diverter

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1. **What is good practice for diverter vent line systems?**
   a. Diverter vent lines should be routinely pressure tested.
   b. Diverter vent lines can have bends as they are not designed to hold high pressures.
   c. Diverter vent line bends can have the full bore rubber hoses installed.
   d. Diverter vent line should have options to allow discharge down-wind of the rig.
2. **As per API standard, what is the minimum pressure test value to verify a diverter assembly installation? 1.**

a)100 psi

b) 300 psi

c) 400 psi

d) 250 psi

3. **What design feature do diverter systems have to minimize back-pressure on the well? 1**
   a) Small internal diameter, with targeted bends and maximum length vents lines.
   b) Dual active vent lines with minimum bore control valves.
   c) Large internal diameter, straight and short vents lines.
   d) The diverter element closes before the selector valve opens.
4. **You plan to batch-drill six top-hole sections with a diverter system which is rigged up below the rig floor. Which type of vent-line will help minimize the pressure build up in the well if there is a shallow gas or water flow?**
   a) A small internal diameter (ID) vent line rigged to discharge overboard.
   b) A large internal diameter (ID) vent line rigged to discharge fluids a safe distance away from the rig.
   c) A large internal diameter (ID) vents line from the diverter to the top of the derrick.
   d) A vent line from the diverter to MGS.

5. **Main advantage of insert type diverter on large conventional annular type?(One Answer)**

   a) Can allow large diameter tools to be run without removing inserts.

   b) Can hold higher pressure as compared to conventional annular type.

   c) Has a lower closing volume and is faster to close.

d) Takes longer time to close and reduces shock on formation.

6. What is the main advantage of an insert diverter compared to a conventional large annular type of diverter? 1

a) An insert type diverter has a lower closing volume and is faster to close on flowing well.

b) An insert type diverter takes longer to close.

c) An insert type diverter can allow large diameter tools to be run without removing the insert.

d) An insert type diverter an insert type diverter can hold higher pressure than z conventional diverter.

7. You are drilling top hole from a platform rig using a surface BOP. An annular diverter has been installed with the flow line located above it and the overboard valves below. The diverter sequence is open both vent lines and close diverter.
The wind is coming from the east. What is the next action? 1

a) Close the overboard vent line to the west
b) Close the overboard vent line to the east
c) Close the flow line before opening the overboard vent line to the east.
d) Close the flow line before opening the overboard vent line to the west.

Number of gallons

8. Given the volumes below, how much hydraulic fluid is required to complete the following operations (no safety margin)?

Operations	Close then open
Equipment	One annular preventer
	Two pipe rams
	One shear/blind ram
Volumes:	
annular preventer:	19 gallons to close. 16 gallons to open.
pipe ram:	7 gallons to close. 6 gallons to open.
shear/blind ram:	7 gallons to close. 6 gallons to open.

a) 58 gallons
b) 74 gallons
c) 68 gallons
d) 61 gallons

9. Given the volumes below, how much hydraulic fluid is required to complete the following operations (no safety margin)?

Operations	Close,open then close again
Equipment	One annular preventer
	three pipe rams
	One kill and one choke line valve
Volumes:	
annular preventer:	12 gallons to close. 9 gallons to open.
pipe ram:	6 gallons to close.5 gallons to open.
Each kill and choke line valve	1 gallons to close. 1 gallons to open.

a) 84 gallons
b) 56 gallons
c) 90 gallons
d) 87 gallons

10. - Given the volumes below, how much hydraulic fluid is required to complete the following operations (no safety margin)?

Operations	Close, then open
Equipment	One annular preventer
	two pipe rams
Volumes:	
annular preventer:	51gallons to close. 45gallons to open.
pipe ram:	25 gallons to close.22 gallons to open.

a. 143 gallons
b. 152 gallons
c. 190 gallons
d. 95 gallons

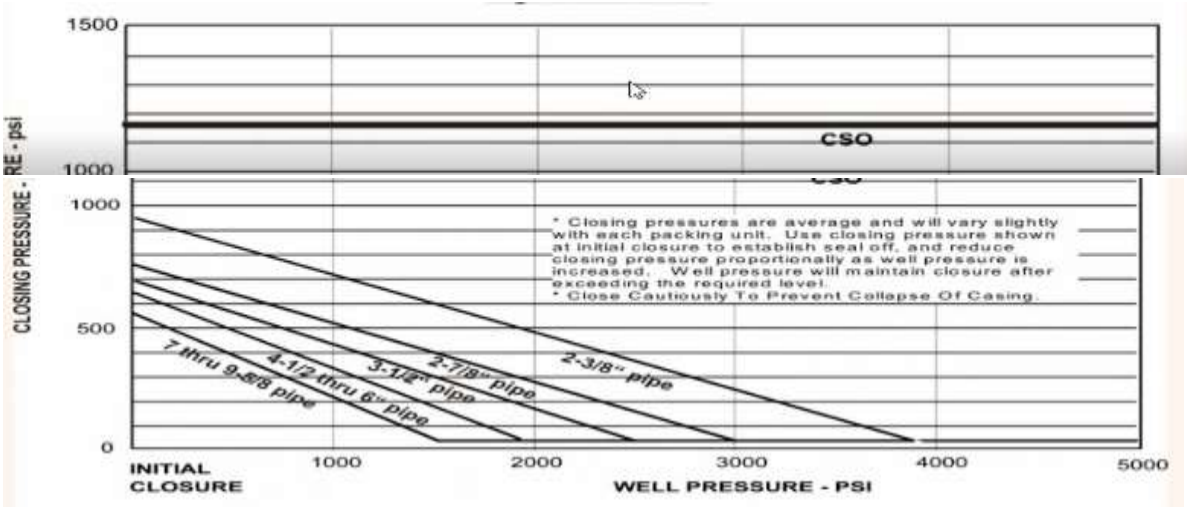
11. Given the volumes below, how much hydraulic fluid is required to complete the following operations (no safety margin)?

Operations	Close, open then close again
Equipment	One annular preventer
	three pipe rams
Volumes:	
annular preventer:	18 gallons to close. 15 gallons to open.
pipe ram:	6 gallons to close. 5 gallons to open.

a) 102 gallons
b) 66 gallons
c) 68 gallons
d) 85 gallons

Charts

12. A surface stack BOP has one 10000 (10k) rated annular preventer.
Use the graph below to identify which well control operation can be carried out using the annular preventer.



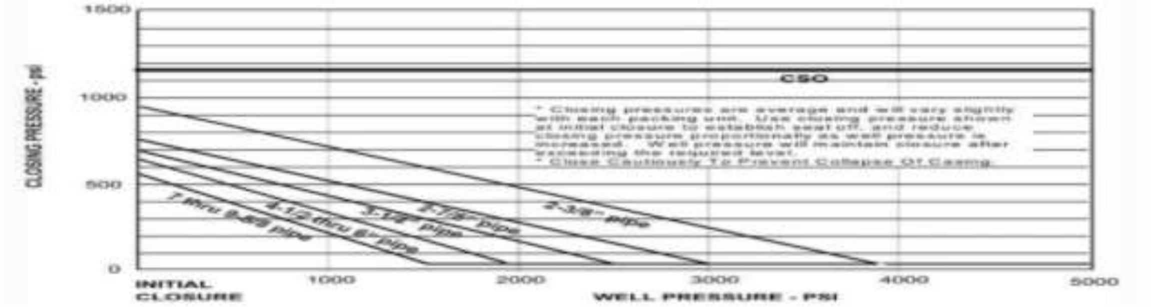
a) Maintain a seal with no pipe in the hole with well pressure of 500 psi and with annular pressure regulated to 1200 psi.

b) Maintain a seal on 5" drill pipe with a well pressure of 500 psi and with annular pressure regulated to 400 psi.

c) Maintain a seal on 8" drill collar with a well pressure of 500 psi and with annular pressure regulated to 350 psi.

d) Maintain a seal on 3 1/2" drill pipe with a well pressure of 500 psi and with annular pressure regulated to 500 psi.

13. There is a 5" D/P in the hole, the well surface pressure is 1000 psi, find out how much the closing pressure for 13 5/8" -5000 annular preventer hydril type "GK" (guide lines to determine intial closing pressure for stripping operations wiyh hydril manufacture annular preventer.



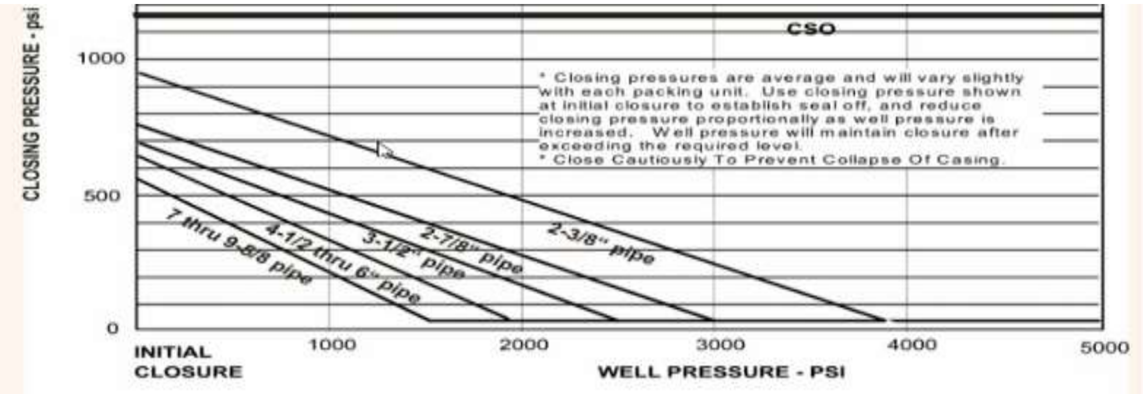
a) 200-300 psi

b) 300-400 psi

c) 400-500 psi

d) 500 psi or above.

14. Use the graph below.



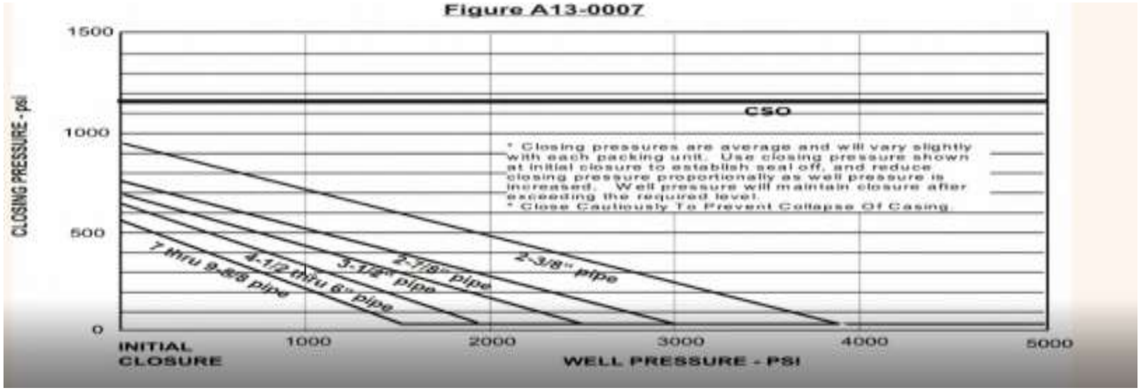
a) Maintain a seal with 2 3/8" pipe in the hole with well pressure of 500 psi and with annular pressure regulated to 900 psi.

b) Maintain a seal on 3 1/2" drill pipe with a well pressure of 500 psi and with annular pressure regulated to 500 psi.

c) Maintain a seal on 8" drill collar with a well pressure of 500 psi and with annular pressure regulated to 350 psi.

d) Maintain a seal on 5 " drill pipe with a well pressure of 500 psi and with annular pressure regulated to 400 psi.

15. Use the graph below to identify which well control operation can be carried out using the annular preventer. 2 answers.



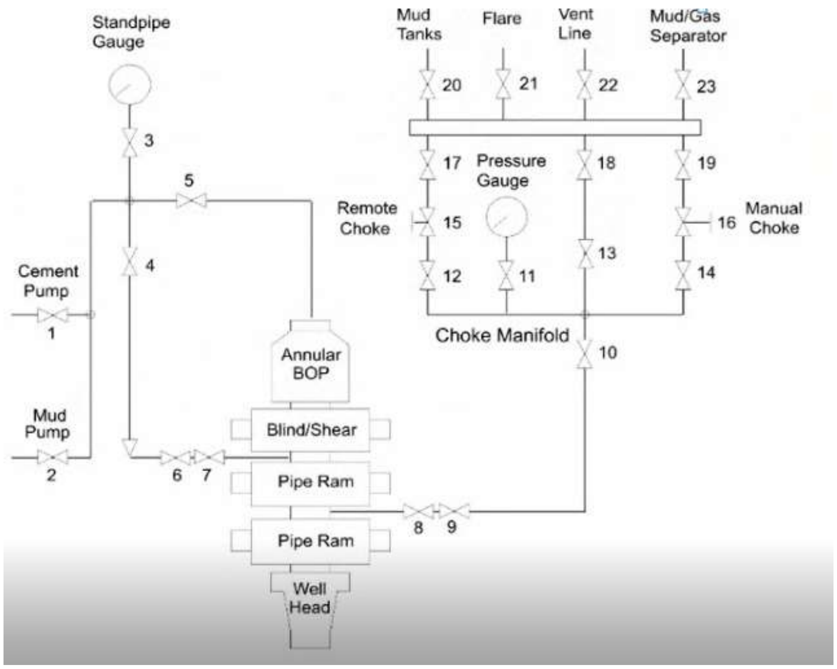
a) Maintain a seal with no pipe in the hole with well pressure of 1000 psi and with annular pressure regulated to 1175 psi.

b) Maintain a seal on 5" drill pipe with a well pressure of 1000 psi and with annular pressure regulated to 375 psi.

c) Maintain a seal on 2 3/8" drill collar with a well pressure of 1000 psi and with annular pressure regulated to 650 psi.

d) Maintain a seal on 3 1/2" drill pipe with a well pressure of 1000 psi and with annular pressure regulated to 400 psi.

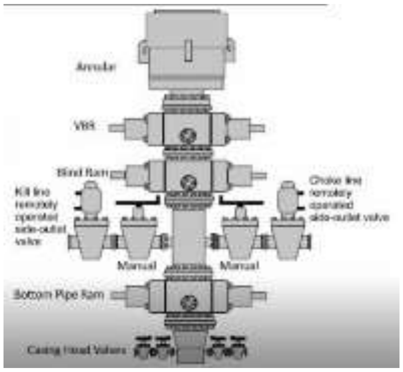
Sketches



16. **Which group of valves and chokes must be open to circulate from the cement pumps through the drill string and bleed off through the remote choke to the mud gas separator (MGS)? 1**

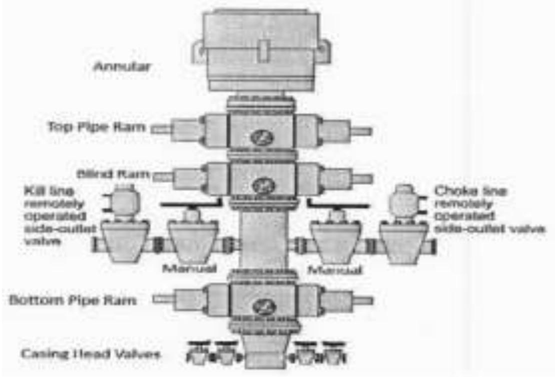
    a) Valve nos. 2,3,4,6,7,8,9,10,11,14,19,23.
    b) Valve nos. 2,3,5,8,9,10,11,14,19,23.
    c) Valve nos. 1.3,4,6,7,8,9,10,11,19,23.
    d) Valve nos. 1,3,5,8,9,10,11,12,15,17,23.

17. **Why is the manual valve and remotely controlled side outlet valve installed in the position shown in the following diagram?**


Annular
VBR
Blind Ram
Kill line remotely operated side-outlet valve
Choke line remotely operated side-outlet valve
Manual
Manual
Bottom Pipe Ram
Casing Head Valves

a) The manual valve act as barrier if the remotely-controlled side outlet valve needs maintained or repaired
b) To increase the back pressure down hole for a safety margin.
c) To protect the remotely controlled side outlet valve from eroding while cementing.
d) To minimize the build-up of cutting at drilling spool side outlets.

18. After pulling out of the hole, a routine function test identifies a failed remotely- controlled side outlet valve on the choke line. Which two barriers must be in place before you can begin to repair the valve? 1

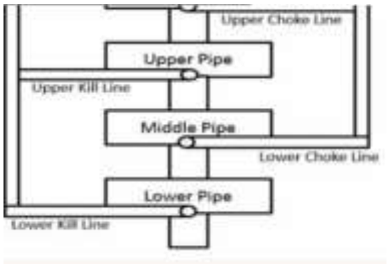

Annular
Top Pipe Ram
Blind Ram
Kill line remotely operated side-outlet valve
Choke line remotely operated side-outlet valve
Manual
Manual
Bottom Pipe Ram
Casing Head Valves

a. The drilling fluid and the bottom pipe ram.
b. A retrievable test packer assembly and the choke line manual valve.
c. A retrievable test packer assembly and the bottom pipe ram.
d. The drilling fluid and choke line manual valve.

19. There is drill pipe in the hole, and you are monitoring the well on the trip tank (next figure), which two barriers must be in place while repairing the choke line remotely-controlled side outlet valve ? 1

a) Both manual stack valves.
b) The drilling fluid and the bottom pipe ram.
c) The manual choke line valve and drilling fluid.
d) The blind ram and the manual stack valve.

20. In the diagram of a 10000-psi surface BOP stack, why is the kill line outlet placed below the lower ram?



a. To allow the well to flow to flare line.
b. To be able to monitor the well or bullhead if the lower ram is closed.

c. To kill the well using the driller's method or wait and weight method.
d. To allow the use of volumetric method.

Inflow test

21. You inflow test the 7 inch Liner Lap using a retrievable packer. The drill pipe is displaced to light weight fluid and the packer is set above the Liner Lap. The BOPs are open and the annulus is monitored on the trip tank.

After bleeding off the initial high pressure, you see an initial increase in the drill pipe pressure before it stabilizes. The trip tank level remains constant. What could this indicate? (Choose 1 answer)

a) This indicates the packer has set correctly.

b) This indicates there is a leak in the liner.

c) This indicates there is a leak in retrievable packer. Trip tank

d) This indicates thermal expansion of the drilling fluid. Over extended period

22. You inflow test the 7" liner lap using a retrievable

packer. The drill pipe is displaced to light fluid and the packer set above the liner lap. The BOPS are open and the annulus is monitored on the trip tank.
After bleeding of initial pressure from 500 psi in stages, you are unable to bleed below 250 psi.
The trip tank level remains constant.
What could this indicates?

a) This indicates that there is a leak in the retrievable packer.
b) This indicates thermal expansion for light weight fluid.
c) This indicates that the packer has correctly set.
d) This indicates that there is a leak in the liner.

23. You inflow test the 7 inch Liner Lap using a retrievable packer. The drill pipe is displaced to light weight fluid and the packer is set above the Liner Lap. The BOPs are open and the annulus is monitored on the trip tank.
While reducing the drill pipe pressure by small amounts, you notice the trip tank level is decreasing. What does this indicate? (Choose 1 answer)

a) The packer is correctly set.

b) Thermal expansion of drilling fluid.

c) The liner lap is leaking.

d) The retrievable packer is leaking.

24. You inflow test the 7” liner lap using a retrievable packer. The drill pipe is displaced to light fluid and the packer set above the liner lap. The BOPS are open and the annulus is monitored on the trip tank.

After bleeding of initial high pressure in stages, you see a gradual initial increase in drill pipe over a period of time. The trip tank level remains constant.

What could this indicates?

a) This indicates that there is a leak in the retrievable packer.
b) This indicates thermal expansion for light weight fluid.
c) This indicates the packer is not set.
d) This indicates that there is a leak in the liner.

25. In which situation would you choose to do an inflow test to verify well barrier element?

a. When pressure testing a liner lap.

b. When pressure testing the choke manifold.

c. When pressure testing the top drive IBOP.

d. When pressure testing the annular preventer.

26. What is the purpose of an inflow test? (Choose 1 answer)

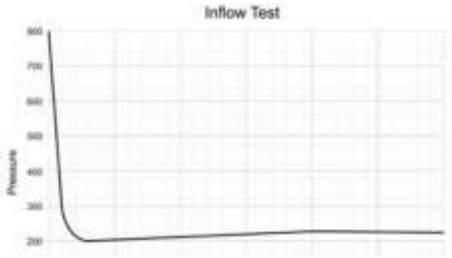
a) To test the barrier element from any direction of the flow by applying positive pressure on the barrier element.

b) To circulate from drill string and take returns from the annulus.

c) To test the barrier element in the direction of flow by applying negative pressure downstream of the barrier element.

d) To test the barrier element in the direction of flow by applying positive pressure upstream of the barrier.

27. **You inflow test the 7" liner lap using a retrievable packer, the drill pipe is displaced to light weight fluid and the packer is set above the liner lap, the BOPs are open and the annulus is monitored on the trip tank, after bleeding off the initial high pressure in stages, the pressure profile in the following figure was seen, the trip tank level remains constant. What could this indicate?**



a) This indicates that there is a leak in the drill pipe connection just above the retrievable packer.

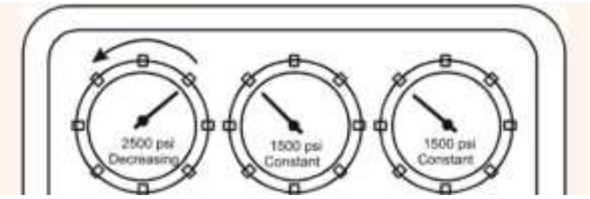
b) This indicates that the packer is not set.

c) This indicates thermal expansion of the light fluid.
d) This indicates that there is a leak in the retrievable packer.

Malfunction

28. **On a surface BOP installation, the driller closes the pipe ram at the remote panel, the close light illuminates but the manifold pressure does not drop. What could have caused this problem? 1**
    a. The hydraulic closing line to the BOP is plugged.
    b. The hydraulic line to the BOP is leaking.
    c. The 3 position/ 4- way valve on the hydraulic BOP control unit failed to operate.
    d. The annular preventer has malfunctioned.

29. **fig. (r32) shows a set of BOP remote control panel gauge reading. The BOP has not been operated and the BOP accumulator charge pumps (electric and air) are not running. What are possible reasons for the low accumulator pressure?**
    Please select 2 answers



a) The accumulator pre-charge pressure is too high.
b) The accumulator charge pump pressure switches have failed.
c) The accumulator pre-charge pressure is too low.
d) There is a leak at the BOP.
e) There is a leak in hydraulic accumulator unit.

30. The driller shut in on a kick with annular BOP using the remote control panel, and activates a pipe ram's close function to protect the annular BOP. The driller reports the following pressures:

Accumulator pressure static: 3000 psi.
Annular pressure static: 1200 psi.
Manifold pressure: 0 psi.
Annular indicator light: red.
Ram indicator light: green.
Why is the manifold pressure reading 0 psi? 1

a. The hydraulic line to the upper pipe ram is blocked.
b. The selector valve is stuck in the open position.
c. The manifold pressure reducing and regulating valve' is malfunctioning.
d. There is a leak in the hydraulic line to the upper pipe ram.

31. The driller activates a ram close function from the remote BOP panel on surface BOP installation. The manifold pressure continues to drop and does not rise back up again. What is the reason for this? 1

a) The hydraulic closing line to the BOP is plugged.
b) There is a leak in hydraulic line to the BOP.
c) The 3-position /4-way valve on the hydraulic BOP control unit failed to operate.
d) The light bulb has blown.

32. After a drilling break, the driller does a flow check. The well is following, and the upper pipe ram is closed. The driller notes and reports the following pressures:

Accumulator pressure is static at 3000 psi

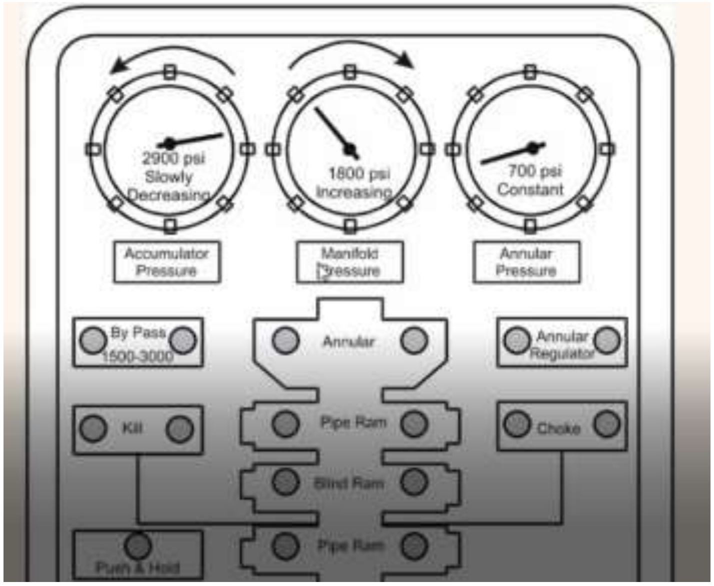
Annular pressure is static at 900 psi.

Manifold pressure decreased rapidly to 0 psi.

Why is the manifold pressure reading zero? 1

a) The manifold pressure reducing and regulating valve is malfunctioning.
b) The selector valve is stuck in the open position.
c) The hydraulic line to the upper pipe ram is blocked.
d) There is a leak in the hydraulic line to the upper pipe ram.

33. Figure below shows a set of BOP remote control panel gauge readings. The BOP has not been operated and the electrically driven pump is not running. What do these gauges readings indicate?



a) The hydraulic circuit is leaking.
b) There is a problem with the automatic hydro-electric pressure switch.
c) There is a problem with manifold regulator.
d) There is a problem with annular regulator.

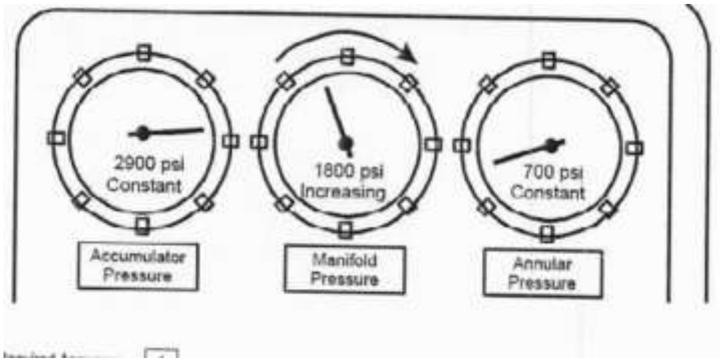
34. When operating a stack function from the remote BOP panel on surface BOP installation. The open light goes out, the close light does not illuminate and manifold pressure drops and later rises back up, which malfunction does this indicate? 1

a) The 3 positions / 4-way valve failed to shift.
b) The close function light bulb has blown.
c) The hydraulic closing line to the BOP is plugged.
d) There is a leak in hydraulic line to the BOP.

35. The driller closes the upper rams from the remote control panel. The green lights indicator turns off and the red light indicator does not turn on. The accumulator pressure and manifold pressure readings decrease and then return to normal. What could be the cause of the malfunction?

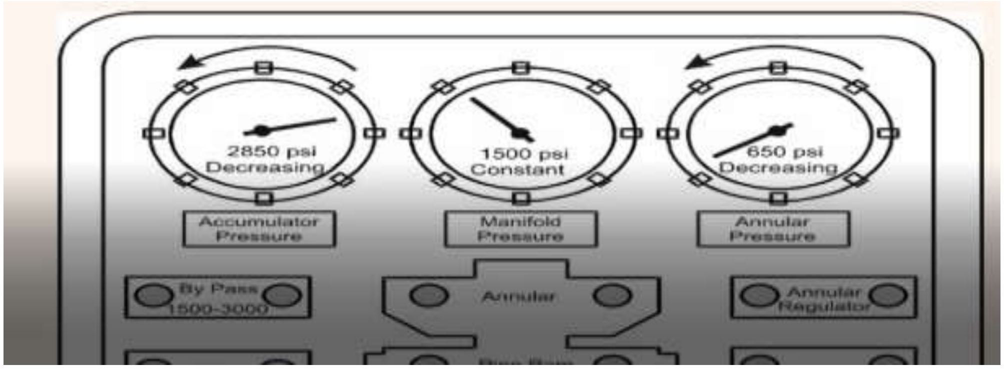
a) The 3 position/4 way valves on the hydraulic BOP control unit did not move.
b) The rams did not close.
c) There is leakage on the hydraulic circuit.
d) There is an electrical fault with lights.

36. Figure below shows a set of BOP remote control panel gauge readings. The BOP has not been operated and the electrically driven pump is not running. What is the reason for increase in the manifold pressure? 1



a) There is a problem with the hydraulic-electric pressure switch.
b) These are normal operating ranges.
c) There is a problem with the hydraulic pressure regulating valve.
d) The hydraulic circuit is leaking.

37. Figure below shows a set of BOP remote control panel gauge readings. The BOP has not been operated and the electrically driven pump is not running. What do these gauge readings indicate?



a) There is a problem with the air operated pressure reducing and regulating valve.
b) There is a problem with the charging pump.
c) There is a leak in the annular hydraulic circuit.
d) The readings are within normal operating reading.

38. You close a ram using the remote operating panel on a surface BOP installation.

The close light does not illuminate and the manifold pressure does not drop.

Which malfunction does this indicate? 1

a) The hydraulic closing line to the BOP is plugged.
b) There is a leak in the hydraulic line to the BOP.
c) The 3 position 4-way valve on the hydraulic BOP control unit gas failed to operate.
d) The light bulb has blown.

39. Accumulator Pressure	**2900**	**psi and slowly decreasing**
Manifold Pressure	**1800**	**psi and increasing**
Annular Pressure	**1500**	**psi and constant**

What do these gauge readings indicate? (Choose1 answer)

a) The hydraulic circuit is leaking.

b) There is a problem with the automatic hydro-electric pressure switch.

c) There is a problem with hydraulic pressure regulating valve.

d) The pressure readings are within normal operating range.

40. Accumulator Pressure	**2900 psi**	**decreasing**
Manifold Pressure	**1450 psi**	**decreasing**
Annular Pressure	**700 psi**	**constant**

What do these gauge readings indicate? (Choose1 answer)

e) There is a leaking in the manifold hydraulic circuit.

f) There is a problem with the by- pass valve..

g) There is a problem with the charging pump.

h) The readings are within normal operating range.

WEAR IN ANNULAR RUBBER

41. How to know if an annular packing element is deteriorated? 3 answers.

a) Closing pressure required to make effective seal increases every test.
b) Having to increase the annular closing pressure above than slandered.
c) Having to increase the pressure after closing in the annular up to slandered.
d) Finding rubber pieces with mud returns at shale shakers.

42. What is the indication that the annular preventer has deteriorated during routine well operations? (Choose 1 answer)

a) Annular 'closed' light fails to illuminate.

b) Closing time on annular element decreases.

c) Drilling fluid leeks from annular weep hole.

d) Pieces of annular rubber found in the drilling fluid returns.

43. On a surface BOP stack, what is an indicator that the annular packing element may be beginning to wear? 1

a) Over several pressure tests the annular closing pressure required for a good test increase.

b) Over several function tests of the annular with drill pipe. There is a decrease in volume required to close.

c) Over several pressure tests the annular closing pressure required for a good test decreases.

d) When closing the annular with a small pipe size in the hole. It holds up to 80% of the annular pressure rating.

44. On a surface BOP stack, what is an indicator that the annular packing element may be beginning to wear? 1

a. Over several function tests of the annular with drill pipe, there is a decrease in the volume required to close.
b. Over several pressure tests, the annular closing pressure required for a good test decreases.
c. Over several pressure tests, the annular closing pressure required for a good test increase.
d. When closing the annular with small pipe size. it holds up to 80 % of the annular pressure rating.

45. During a pressure test of a stack annular preventer, the closing pressure must be increased to achieve a successful test. What could be happening? 1

a) Regulated annular pressure should always be regulated.

b) The annular element start to deteriorate, and my need to be replaced soon.

c) The annular regulator is damaged.

d) The annular element material is not correct for drilling

fluid type.

Draw down test

46. Accumulator test performed on a 15K stack. Once all functions are performed remaining accumulator pressure is 1380 psi. Interpretation? (Choose 1 answer)

a) Pressure is too high, we need to reduce pressure.
b) Pressure is too low, we need to add more bottles.
c) Pressure is too low, we need to increase pre-charge.
d) Pressure is above the minimum pressure required.

47. An accumulator draw down test is performed on a 15000 surface BOP stack. Once all required functions were performed. The remaining accumulator pressure is 1380 psi. What is your interpretation of this test? 1

a. The remaining pressure is too low; we need to add more bottles. 18 ¾”
b. The remaining pressure is too high; we need to reduce the regulated pressure.
c. Check the manufacture’s maintenance system to confirm you can continue.
d. The remaining pressure is too low; we need to increase the pre charge pressure.

48. An accumulator draw down test is carried out
The final pressure recorded: 1160 psi
After 15 minutes, the pressure increase to 1240 psi.
What should you do?

a) Wait another 15 minutes. if the final pressure is less than 1400 psi, Class the test as fail

b) Class the test as pass, activate the charge pumps to charge the bottles to normal operating pressure, and continue with next operation.
c) Class the test as fail, bleed down the bottles.
d) Wait another 15 minutes if the final pressure is more than 1400 psi, Class the test as pass.

49. After draw down test is performed, the remaining pressure is 1380 psi.
What is your interpretation ? 1

a) The remaining pressure is too low, and we need to add more bottles.
b) The remaining pressure is too low, and we need to increase pre-charge pressure.
c) The remaining pressure is too high, and we need to reduce regulated pressure.
d) The remaining pressure is too low, and we need to add more bottles.
e) Check the manufactures maintenance system to confirm you can continue.

50. An accumulator drawdown test is performed on a 15K surface BOP. Once all the required functions were performed, the remaining pressure is 1380. What is your interpretation?
(Choose 1 answer)

b) The remaining pressure is too low, need to reduce the regulated pressure.

c) The remaining pressure is too low, need to add more bottles to the system.

d) The remaining pressure is tool low, need to increase the pre-charge pressure.

e) The remaining pressure is above minimum pressure required to work, continue operations.

51. An accumulator drawdown test is carried out on a surface BOP stack to API Standard 53.
Accumulator bottle pressure 3000 psi.
Pre-charge pressure 1000 psi.
Final pressure recorded 1160 psi
After 15 min the pressure increased to 1240 psi. What should you do? (Choose 1 answer)

a. Fail; bleed down the bottles and check Pre-charge pressure. Continue with operation.

b. Pass; activate the charge pumps to charge the bottles to normal operating pressure. Or (classify the test as pass)

c. Wait 15 min, if the final pressure is less than 1400 psi, class the test a fail. Check the pre-charge pressures.

d. Wait 15 min, if the final pressure is more than 1400 psi, class the test a pass. Continue with next operation.

Three answers questions

52. A drill pipe safety valve (DPSV) should be placed on the rig floor all times ready for use to fit the tubular in use, which statements are correct for this type of valves? choose 3 answers

a. It will not allow wire line to be run inside the drill string.
b. It should not be run in the hole in the closed position.
c. It requires key to open and close.
d. It will be installed in the closed position.
e. It has to be pumped open to read shut in drill pipe pressure (SIDPP).
f. Its rated operating pressure is less than that of drilling BOP.
g. It is easier to stab than an IBOP when there is a flow up drill string.
h. It is kept in the open position by rode secured by T handle.

53. A conventional flapper type float valve is installed in the bit sub. What effect does this have on the operation when tripping into the well compared to a drill string without a float? 3 answers

a) The drill pipe may collapse if it is not filled.
b) Surge pressure on the formation will decrease.
c) The shut-in pressure (SIDPP) will be equal to the shut in casing pressure (SICP).
d) Back flow through the drill string will increase.
e) Reverse circulation will be possible.
f) Surge pressure will increase.
g) There will be increased mud returns to the trip tank.

54. IBOP should be placed on the rig floor at all times, ready for use, to fit the tubular in use.Which of the following are correct for this type of valve? 3 answers.

a. It is kept in its opening position by a rod secured by a T-handle.
b. It can be run in the hole in the open position.
c. It cannot be pressure tested before use.
d. It will not allow wire line to be run inside the drill string.
e. It is easier to stab than a drill pipe safety valve (DPSV) when flow is encountered up the drill string.
f. It has to be pumped open to read the SIDPP.
g. It has the potential to leak through the open/close key socket.

Tests

55. How often should all operational components of the surface BOP stack equipment system be function tested according to API slandered 53? 1

a. Once a shift.
b. Once every 14 days.

c. At least once a week.
d. Once after installation on BOP stack.

56. DPSV and IBOP must be pressure tested at the same time interval as the BOP stack. As per standard 53 (2018), what test pressure should be applied at initial test on the rig

a) High pressure at maximum anticipated surface pressure followed by low pressure of between 250 psi and 350 psi.
b) High pressure at the rated working pressure of the components low pressure between 250 psi and 350 psi.
c) Low pressure of between 250 psi and 350 psi followed by a high pressure test at maximum anticipated surface pressure (MASP) for the well programme.
d) Low pressure of between 250 psi and 350 psi followed by high pressure at the rated working pressure of the component.

57. How should the manually operated and hydraulically operated kill line valves on the BOP be pressure tested? 1

a) From the well bore side, with the check valve installed.
b) From the pump side, because the check valve on the outside of the valve prevents the detection of a faulty valve if they are pressure tested from the well bore side.
c) From the well bore side, with the check valve removed and the kill line vented.

58. When should well control equipment on a surface BOP installation be pressure tested? 2.

a) Before spuding or upon installation.
b) After the disconnection or repair of any pressure containment seal in the BOP system, choke line or choke manifold.
c) At intervals not exceeding two months.
d) After circulating out a gas kick.

59. Drill Pipe Safety valves (DPSVs) and Inside Blow out Preventers (IBOPs) must be pressure tested as frequently as the BOP stack. Per API Standard 53, what minimum test pressure should be used in the subsequent high-pressure tests? (Choose 1 answer)

a) Maximum anticipated surface pressure of the hole section.
b) 250 psi to 350 psi.
c) Rated working pressure of the component.
d) 150% of the rated working pressure of the component.

60. During regular subsequent BOP testing. What high pressure value should drill pipe safety valves (DPSVs) and an inside BOP (IBOPs) be tested to? 1

a) The rated working pressure of the rotary hose.

b) The maximum anticipated surface pressure.

c) The lower of maximum anticipated surface pressure or 70% of the annular rated working pressure.

61. You are supervising the weekly BOP function test on a surface 18 3/4"inch x 10000 psi BOP stack. The regulated manifold pressure is 1500 psi.

.And the regulated annular pressure is 1000 psi. What would tell you that the annular has closed correctly?

a. The ram light should change from open to close and 23 seconds later manifold pressure should read 1000 psi.
b. The annular light should change from open to close and 60 seconds later the annular pressure should read 1000 psi.
c. The ram light should change from open to close and 23 seconds later manifold pressure should read 1500 psi.
d. The annular light should change from open to close and 43 seconds later the annular pressure should read 1000 psi.

62. You are supervising the weekly BOP function test on a surface 13 3/8"inch x 5000 psi BOP stack. The regulated manifold pressure is 1500 psi.

.And the regulated annular pressure is 1000 psi. What would tell you that the ram has closed correctly?

a. The ram light should change from open to close and manifold pressure should read 1500 psi within 30 seconds.
b. The annular light should change from open to close and manifold pressure should read 1500 psi within 45 seconds.
c. The ram light should change from open to close and manifold pressure should read 1000 psi within 30 seconds.
d. The annular light should change from open to close and annular pressure should read 1000 psi within 45 seconds.

63. As per API RP 53 , when should you pressure test your drill pipe safety valve and inside blow out preventer? 1

a) Each time a new component added.

b) Once a week.

c) At each function test.

d) At interval not exceeding 21 days.

64. P/T FOSV & IBOP

a) with the initial BOP initial pressure test & subsequent intervals
b) once installed on string
c) with function test on BOP

65. According to API standards, how often should a function test on all the components of a surface BOP be performed during well operations? (Choose 1 answer)

a) At least every 2 weeks (14 days).

b) At least every 3 weeks (21 days).

c) At least every week (7 days).

d) Before spudding or after installation.

66. Your rig is equipped with a 15000 psi Surface BOP stack. What test-pump instrument and equipment ratings are required to test this BOP? (Choose 1 answer)

a) 10,000 psi

b) 15,000 psi.

c) 16,000 psi.

d) 20,000 psi.

67. Why should the side outlet valves below the test plug be kept in the open position while testing a surface BOP stack? 2

a) If not kept open, reverse circulation will be needed to release the plug.
b) Because the test will create extreme hook load.
c) To monitor the annulus for plug leakage.(to monitor the well bore for plug leakage).
d) To check the position of the test plug.
e) To prevent potential damage to the casing or formation.

68. When testing the BOP stack with a test plug or cup type tester, why is pressure communication maintained from below the tool to atmosphere? 1

a. To avoid to the casing-open hole potential damage(To avoid potential damage to the casing-open hole)

b. To avoid the creation of extreme hook load.

c. Otherwise reverse circulation will be needed to release the tool.

d. To avoid swabbing a kick during the test.

69. Who should sign the pressure test documentation?

a. The mechanic, the installation manager, and the electrician.

b. The pump operator, the drilling contractor representative, and the well operator representative.

c. The mechanic, , the drilling contractor representative and the BOP engineer.

d. The driller, the tool pusher, and the cement pump operator.

70. During regular weekly function test of 13 5/8" surface stack, the supervisor records the following data. Does this stack pass the function test as per API 53?

Function	Closing pressure	Time (sec.)	olume to close Gallons	olume to open Gallons
Annular	**500**	**47**	**43**	**35**
Top ram	**1500**	**23**	**11.5**	**13.6**
Middle ram	**1500**	**37**	**11.4**	**13.6**
Lower ram	**1500**	**22**	**11.5**	**13.5**
HCR CHOKE LINE	**1500**	**4**	**2.1**	**2.2**
HCR KILL LINE	**1500**	**5**	**3**	**2**

a) No, all kill and choke line valves exceeded the minimum response time.

b) Yes all values meet requirement.

c) No, the middle ram and annular preventer closing are too long.

d) Yes, more than half of the BOP functions meet the requirement.

71. How often should all operational components of BOP be functioned tested?

(Choose 1 answer)

a) Not exceeding 21 days

b) Once per week (weekly)

c) On installation

d) 2 months.

72. The BOP test pump is connected to the kill line on a surface stack. A plug type tester is in position and connected to the drill pipe. How can you tell if the tester plug is leaking?

(Choose 1 answer)

a) Check for a pressure increase at the manual choke.

b) Check if the test pump can reach the required pressure.

c) Monitor for flow back up the drill pipe.

d) Open the choke line valves through the Mud Gas Separator.

73. Drill Pipe Safety valves (DPSVs) and Inside Blow Out Preventers (IBOPs) must be pressure tested at the same time interval as the BOP stack. Per API Standard 53 (2018), what test pressures should be applied at the initial test on the rig? (Choose 1 answer)

a) High pressure at the rated working pressure of the components followed by low pressure of between 250 psi and 350 psi.

b) High pressure at the maximum anticipated surface pressure of the well followed by low pressure between 250 psi and 350 psi.

c) Low pressure of between 250 psi and 350 psi followed by a high pressure test at the maximum anticipated surface pressure of the well

d) Low pressure of between 250 psi and 350 psi followed by high pressure at the rated working pressure of the component.

74. Drill Pipe Safety valves (DPSVs) and Inside Blow out Preventers (IBOPs) must be pressure tested at the same time interval as the BOP stack. Per API Standard 53, what test pressures should be applied at the subsequent high pressure tests? (Choose 1 answer)

a) 150% of the rated working pressure.

b) Between 250 psi and 350 psi.

c) Rated working pressure of the component.

d) Maximum Anticipated Surface Pressure (MASP) for the hole section.

75. What tests should you do when testing the remote choke to API standard 53? 1

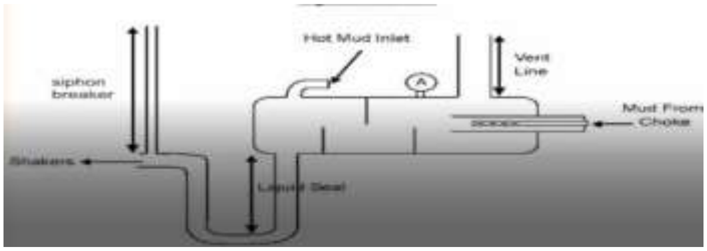
a. Function test the primary control system, and then test the manual choke at the next test .
b. Functions test the primary control system only.
c. Function tests both primary and back-up control systems.
d. Only function test at the API “initial test”

MGS and VACUUM DEGASSER

76. While circulating out a kick, pressure begins to build up in MGS. Why can this be dangerous?

a) Pressure build up in MGS may allow gas to enter the shale shaker area.
b) Pressure build up in MGS may allow gas to be diverted up the derrick vent line.
c) Pressure build up in MGS will increase the risk of lost circulation.
d) Pressure build up in MGS will make it difficult to adjust the choke.

77. When a mud gas separator (MGS) is operating within its handling capacity, which design features create the back pressure on pressure gauge “A” shown in figure)



A. The height and the diameter of the siphon breaker.
B. The height of the liquid seal.
C. The length and diameter of the vent line.
D. The flow rate of hot mud into MGS.

78. What is the primary reason to use vacuum degasser when circulating out a gas kick? 1

a) It removes entrained gas from the fluid returning to the mud pits.
b) It can handle large volumes of free gas.
c) It vents recovered gas through the kill line to the rig flare line.
d) It has limited volume capacity.

79. When circulating out a gas kick at 30 SPM, the pressure inside the MGS increases to the maximum allowable pressure.

What should you do to reduce the risk of liquid seal loss in the MGS U-tube? 1

a) Shut in the well and bullhead the gas back to the casing shoe.
b) Shut in the well and then re-establish circulation at lower SPM.
c) Shut in the well in and bleed the gas to reduce the casing pressure.
d) Increase the SPM to circulate the gas through the MGS faster.

80. How does a vacuum degasser work? 1

a) Gas cut mud enters the degasser and forms a thick layer over the external baffle plates. Excess pressure inside the vessel forces the gas to escape.
b) Gas cut mud enters the degasser and forms a thick layer over the external baffle plates. The vacuum inside the vessel helps remove the gas.
c) Gas cut mud enters the degasser and forms a thick layer over the external baffle plates. The atmospheric pressure in the vessel helps remove the gas.
d) Gas cut mud enters the degasser and forms a thick layer over the external baffle plates. It is vented to the overboard line.

81. What does a vacuum degasser do? (Choose 1 answer)

a) It is used to remove excess barite from the drilling fluid downstream on the shale shakers.

b) It removes drilled solids from the drilling fluid upstream of the shale shakers.

c) It removes large volumes of gas from the drilling fluid upstream of the shale shakers.

d) It removes gas from the drilling fluid downstream of the shale shakers.

82. Can a vacuum degasser be used instead of a mud gas separator during well control operations? (Choose 1 answer)

a) No, because its position and function makes it unsuitable to handle large volumes of gas.

b) No, because the mud gas separator is used to determine the gas density.

c) Yes, because the flow rate used during a well kill I small.

d) Yes, because they perform the same function.

83. The maximum operating pressure allowed in mud gas separator (MGS) is often calculated assuming there is mud in the liquid seal.

What would be the effect on the maximum operating pressure as condensate (or oil) kick is circulated through the MGS? 1

a. Maximum operating pressure would increase.
b. There would be no effect.
c. Maximum operating pressure would decrease.

84. What pressure should be used to determine the rated working pressure of the ram type BOP to be installed in the well? 1

a. Maximum anticipated surface pressure.
b. Maximum anticipated BHP.
c. Maximum anticipated pore pressure.
d. Maximum anticipated hydrostatic drilling mud pressure.

85. When a ram type BOP on a surface stack is closed, what happens to the operating fluid displaced from the opening chamber? 1

a. The fluid returned to the reservoir
b. The fluid is vented into cellar.
c. The fluid drains into the well bore.
d. The fluid is used to boost the closing pressure.

86. What is the advantage of self-adjusting ram lock? 1

a. As the ram rubber wears the lock position changes to maintain a seal around the pipe.
b. The ram piston moves the same distance each time the ram is operated.
c. As The ram rubber wears; the closing pressure can be reduced to minimize further wear.
d. The ram closes quickly to minimize the size of influx.

87. During well control operation with middle pipe ram closed and shut-in against 4000 psi. It is decided to strip the tool joint through the middle pipe ram?

Rated Working Pressure 15000 psi
Nominal size 7 1/16
Closing ratio 6.9:1
Opening ratio 2.2:1

What is the driller's next step? (Choose 1 answer)

a) Close bottom ram and bleed off pressure from above.

b) Initially close upper ram above tool joint then activate the by pass function on the BOP panel to get sufficient opening pressure from the accumulator then open the middle ram

c) Initially close upper ram above tool joint then open the middle pipe ram.

d) Initially close the upper pipe ram above the tool joint then pump 4000 psi pressure between middle and upper pipe ram then open the middle pipe ram.

e) SIDPP would be lower than expected.

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88. Using the trip sheet below, what action should the supervisor take?

Note: The pipe will be pulled dry.

DP Capacity = 0.0177 bbl/ft DP Displacement = 0.0069 bbl/ft				
Stands Pulled	Length pulled (ft)	Total Length (ft)	Calculated Displacement (bbl)	Trip tank Volume (bbl)
-	-	-	-	15
1 - 5	462	462	3.2	11.8
6 - 10	464	926	3.2	8.6
11 - 20	930	1856	6.4	3
15 bbl added to trip tank				18
21 - 30	928	2784	6.4	11.6
31 - 40	927	3711	6.4	5.2

(Choose 1 answer)

a) Stop tripping, flow check the well. If flow is confirmed, run back to bottom.

b) Stop tripping, flow check the well. If there is no flow, circulate the well.

c) Stop tripping, flow check the well. If there is no flow, run back to bottom.

d) Stop tripping, flow check the well. If there is no flow, continue to POOH.

89. Why is hydrocarbon gas influx easier to detect in water-based drilling fluid than oil-based drilling fluid?

(Choose 1 answer)

e) Hydrocarbon gas has a higher bubble point in water-based drilling fluid.

f) Hydrocarbon gas has a lower bubble point in water-based drilling fluid.

g) Hydrocarbon gas is in-soluble in water-based drilling fluid.

h) Hydrocarbon gas is soluble in water-based drilling fluid.

90. A kick is shut-in with a 10000 psi rated annular (pressure tested to 7500 psi)
During pressure up, you decide to close the pipe ram due to increasing pressure. The final stabilised Shut in Casing Pressure (SICP) is 10800 psi. The pipe ram closing ratio is 7:1. You decide to close the middle ram; function test recorded a minimum of 300 psi to close the ram due to internal friction. What is the minimum operating pressure required to close the middle ram?(One Answer)

a) Approximately 1200 psi.

b) Approximately 1500 psi.

c) Approximately 1850 psi. = 10800/7 + 300 = 1850 psi

d) Approximately 1350 psi.

91. A multi ram surface stack is configured top to bottom.

Annular -Shear rams -Upper pipe rams -Drilling spool with side outlet valves. - Lower pipe rams.

In a well control situation, the annular BOP has a sever leak. The driller activates the upper pipe ram close function and sees that the manifold pressure decreases rapidly.

The accumulator pressure start to decrease and the charge pumps activate.
Which action is required to shut in the well as quickly as possible ? 1

a) Activate the bypass function.
b) Place the upper pipe ram selector valve in the open position. Then close the ram manually by using the ram lock screws.
c) Send the assistant driller to manually operate the stuck selector valve from closed position to open position.
d) Place the upper ram in the open position; wait for manifold pressure to increase to normal. Then close the lower pipe ram.

92. What is a locking device on a ram-type preventer designed to do? 1

a) Allow the ram to close around the drill pipe.
b) Prevent the ram from opening if there is loss of hydraulic power.
c) Assist the annular preventer to create a seal against the well pressure.
d) Locks the manifold pressure so it cannot be changed.

93. While tripping out of the hole, the wellbore pressure-assisted annular BOP is shut in due to an influx.

If shut in casing pressure 500 psi and the manufacture's chart recommends a minimum closing pressure of 400 psi.
When would the driller adjust the closing pressure? 1

a) When the gas reaches the BOP stack.
b) When (before) stripping in (the) hole.
c) Before shut-in the well.
d) When the pumps are up to kill speed.

94. While tripping out of the hole, the wellbore pressure-assisted annular BOP is shut in due to an influx.

You decided to strip back to bottom to perform the kill operation.
When would the driller adjust the closing pressure to manufacture's recommendation while maintaining a seal? 1

a) When the gas reaches the BOP stack.
b) When the shut in casing pressure (SICP) stabilizes.
c) Before shut-in the well.

d) When the pumps reach to kill speed.

95. What information must be included in the space out diagram for surface BOP stack? 1

a) The distance from BOP to the packer overshot.
b) The distance from the well head to the shear ram.
c) The depth (TD) of the current well section below the rotary table
d) The distance from rotary table to the shear rams

96. a surface stack BOP consists of(top to bottom):

1 x 10000 psi rated annular preventer.—

/ 1 x 10000 psi rated 5” 7” variable ram.

1 x 15000 psi rated blind/shear ram.

Drilling spool (10000 HCRs)—/

1 x 10000 psi rated 5” pipe ram.

Which operation can you do with string 3000 ft. off bottom keeping control oF BHP?

a) Stripping 5” pipe through the annular.
b) Circulating the influx immediately while shut in on 6 5/8” pipe.
c) Stripping to VBR
d) Circulating out the influx while shut in on lower pipe ram.

97. 15000-psi rated surface stack BOP has rams with the following closing ratio.

5” pipe rams	**10.2 :1 Closing ratio**
Blind/shear	**6.8 : 1 Closing ratio**
Variable bore rams	**8.7 : 1 Closing ratio**

Which operation can be completed using 1500 psi manifold operating pressure?

a) Strip 5” pipe to bottom ram to ram at the full rated pressure for the stack.
b) Shut in on 5” pipe at the full rated pressure for the stack.
c) Shut in on 6 5/8” pipe at the full rated pressure for the stack.
d) Shear 5” pipe the full rated pressure for the stack.

98. You are closing a pipe ram from the remote panel on a surface BOP.
The close light illuminates and the manifold pressure gauge initially drops and then returns to normal.
What causes these changes in manifold pressure? 1

a) The accumulator 4-way valve has shifted to neural position.
b) Fluid is flowing into the pipe ram opening chamber.
c) Fluid is flowing into the pipe ram closing chamber.
d) A pilot signal is being sent to the accumulator charge pumps.

99. Which one of the following statements about an IBOP is correct? 1

a. It allows reverse circulation when installed in the drill string.
b. It can be opened by drilling fluid pumped down the drill string.
c. It can be opened or closed by turning a wrench connected to operating crank.
d. It requires a double box sub in order to established in the drill string.
e. It requires a double box sub in order to be installed in the drill string.

100. From which ram operation, is it most likely that the by-pass valve on a surface hydraulic BOP control unit will be used? 1

a. The annular preventer.
b. Variable bore rams.
c. Fixed bore pipe rams.
d. Blind/shear rams.

101. A BOP stack and well head have the pressure rating:
Well head: 10000 psi

Pipe ram: 10000 psi
Blind-shear rams: 10000 psi

Side outlet valves: 10000 psi

Annular: 5000 psi.

String valves (FOSV and non-return): 10000 psi

Rotary hose: 7500 psi.

Choke manifold and pipework upstream of chokes: 10000 psi.

Choke manifold and pipework downstream of chokes: 5000 psi.

If maximum anticipated surface pressure is 8200 psi, what changes are required to ensure pressure integrity? 1

a. Replace the first valves downstream of chokes with 10000-psi rated valve.
b. The stack rating is acceptable; no changes are required.
c. Replace the 5000-psi annular with a 10000-psi rated annular.
d. Replace the 7500-psi rotary hose with a 10000-psi rated hose.

102. What is the main limitation of drill string flapper valves when stripping to bottom? 1

a. You must run wire line inside the drill string to open the flapper valve.
b. You must reverse circulate before stripping to bottom.
c. The shut-in drill pipe pressure (SIDPP) cannot be read on surface.
d. The flapper valve is not a tested barrier.

CHOKE MANIFOLD

103. Why is the recommended diameter for the choke manifold bleed line (the line that by-passes) the chokes) the same diameter as the other lines in the choke manifold.

a) To allow the well to be circulated while maintaining a minimum back pressure.
b) To allow use of a flow meter during high volume bleed-off.
c) To prevent the over-loading of the MGS while maintaining back pressure on the well using the choke.
d) To prevent hydrates from forming.

104. Why do choke manifolds have two chokes?
(why are two chokes incorporated in most of the choke manifolds?

a. To direct returns to mud pits.

b. To provide a backup if there are problems with the active choke.
c. To direct returns to the MGS.
d. To direct returns to the flare.
e. To simultaneously direct the flow into vent line.
f. To allow the kick to be circulated at higher rat.

105. What is the API slandered 53 definition of "rated working pressure" ? 1

a. Twice the rated working pressure of the test tool used.
b. The maximum internal pressure that the BOP equipment is designed to hold.
c. The test pressures that BOP equipment is designed to contain or control.
d. The proof test pressure of a body or shell member.

106. You are tripping out of the hole and are 5000 feet off bottom, when the well starts to flow. Which type of DPSV should you use to secure the well and to strip back to bottom? 1

a) Drop a dart valve into the string and pump to the dart sub to secure the well. Then add a non-return type IBOP for stripping.
b) Install a full-opening type DPSV to secure the well. Then install a non-return type IBOP above for stripping.
c) Install a non- return type IBOP to secure the well, then add a FOSV above for stripping.
d) Install a float valve on the pipe to secure the well then add IBOP above for stripping.

107. Before cutting the drilling line with the bit at casing shoe, which item of equipment must be installed to make the operation safe? 1

107A You are planning a routine slip and cut operation with the bit at the casing shoe. Which item of equipment must be installed to make the operation safe? 1

a. A full opening DPSV in the open position.
b. A circulating head in the closed position.
c. A DPSV in the open position and IBOP in closed position.
d. An IBOP in the closed position.

108. What is the advantage of using a float valve in the drill string? 1

a) To reduce surge pressure.
b) To allow reverse circulation.
c) To avoid back-flow while tripping or during a connection
d) To read the drill pipe pressure after a well kick.

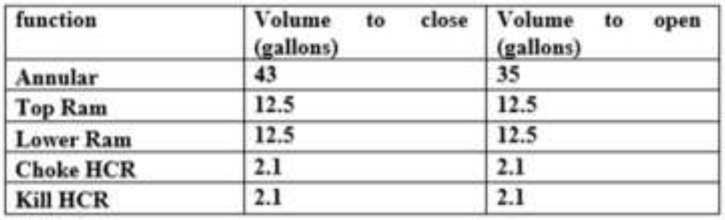
109. During a trip out of hole, the driller shuts in the well using a full opening drill pipe safety valve (DPSV) and the annular preventer.
An IBOP is installed above the DPSV.
With the DPSV open, which of the following is possible? 1

a. Circulation is only possible when a double- box sub is installed between the IBOP and DPSV.
b. Reverse circulation.
c. Circulation is possible when the IBOP has been opened by the operating pressure key.
d. Circulation down the drill string and up the annulus.

110. Why should "space out distances" for different BOP types on the stack be posted where the driller can see them? 1

a. To prevent closing the shear ram around a tool joint.
b. To ensure that the annular is closed around a tool joint.
c. To prevent a pipe ram closing around the pipe body.
d. To ensure the tool joint is opposite the flow line when closing a BOP.

111. The well has just been shut in using the upper pipe ram.
The flow meter reads 7.2 gallons.
The accumulator pressure has returned to 3000 psi.



function	Volume to close (gallons)	Volume to open (gallons)
Annular	43	35
Top Ram	12.5	12.5
Lower Ram	12.5	12.5
Choke HCR	2.1	2.1
Kill HCR	2.1	2.1

Does the function pass correctly?

a. No, the flow meter value is correct but manifold pressure is too low.
b. No, the flow meter value is too low
c. Yes, all pressure values are correct.
d. Yes, the flow meter value is correct.

112. The force required to shear the pipe can be greater than the force required for a pipe ram to seal around drill pipe.

What are the main design features of a shear ram that create the required shearing force?

a. The length of piston stroke and closing pressure.
b. The ram rod diameter and closing pressure.
c. The shear rams closing ratio and closing pressure.
d. The shear rams opening ration and opening pressure.

113. During a routine test, you see that the weep hole (drain hole/ vent hole) on one of the ram type BOP bonnets is leaking drilling fluid. What action is required? 1

a) The primary ram shaft seal is leaking. Secure the well and replace it immediately.
b) Energise the secondary (emergency) seal. If the leak stops, leave it until the next maintenance schedule.
c) The weep hole only checks the closing chamber seals. Leave it until the next maintenance schedule